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# **Modified RPS Calculator: Inputs, Updating Procedure, and Outputs**

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## **ABSTRACT**

This report provides an overview of the modified version of the renewable portfolio standard (RPS) Calculator model. In this report, we describe the inputs and outputs of the modified model, show the method used for updating demand and the resulting effects on the outputs, explain the procedures to set up the model for running, and provide an approach for reinstalling the model on a new RPS Calculator version. The model estimates the benefits of Electric Program Investment Charge (EPIC) research, which lowers the cost or affects the technical parameters (e.g. capacity factor) of renewable and conventional energy generation, electricity demand levels, emissions, fuel costs, and system losses. The general logic of the model is as follows: EPIC projects affect the parameters (inputs) used inside the model; the average effect on the parameters of the model is then determined by the market penetration of the technology; values for the effects on the parameters are drawn repeatedly from one of the few statistical or empirical distributions to reflect specific estimates of penetration for each draw; finally, the model is run with the new random inputs considering all random effects, and the changes in outputs are stored.

The modified version also incorporates a demand estimation procedure based on electricity prices. The original RPS Calculator model makes use of fixed demand forecasts. The EPIC version employs Short-run and Long-run demand functions that are responsive to prices, and estimates the demand endogenously. Based on new electricity prices (costs) obtained from running the RPS Calculator, all demand elements are iteratively updated using the demand functions. This report also reviews the system-wide effects of using price-responsive demand in comparison with using fixed demand forecasts.

The last section of the report explains how the model can be installed on newer versions of the RPS Calculator. CPUC and Energy and Environmental Economics (E3) will update the RPS Calculator regularly. This report describes the steps needed to attach the existing Visual Basic (VB) programs and to add the EPIC's model-specific sheets to the new RPS Calculator. The result will be a new EPIC model which can be run using the new RPS Calculator features. Also, we listed a number of important possible modifications that can be made to improve the model.

## INTRODUCTION

This report and a following report (Rouhani, 2013c) document the modified version of the RPS Calculator, developed to evaluate the EPIC projects' effects on the electricity sector. This report focuses on the Excel spread sheet data/calculations. In this report, we explain the following issues:

- what information is required to run the model,
- which parameters can be changed in the model,
- how referencing the inputs of the original RPS Calculator is done,
- the way to adapt demand responsiveness to prices in the model and its effects on the results,
- how the model should be set up, and finally
- how we can reinstall the model on the new RPS Calculator versions.

For more information on the “Randomizer” program and the code, readers are referred to Rouhani (2013c).

## ORIGINAL RPS CALCULATOR

### *Procedure*

The RPS Calculator (RPS Calculator website, 2012) is a Microsoft Excel spreadsheet partial equilibrium model. Aggregating the renewable cost and performance data, the RPS Calculator selects portfolios of renewable resources needed to meet the RPS target(s), which mandates that 33% (or other percentages) of the Investor Owned Utilities (IOUs) retail sales should be generated from renewable resources by 2020 (SBX 1-2, 2012).

The RPS calculations start with a statewide estimation of the renewable resources that the California utilities must procure between 2008 and 2020 to meet different RPS targets by 2020. The resources needed are then calculated as the total required quantity of renewable energy in 2020 (RPS percent of retail sales) minus the actual renewable generation that was claimed by California utilities in 2007. Then, projects are ranked using a modified version of RETI's “net value” approach. Using the RETI Environmental Working Group's assessment, a project scoring system was developed and used.

The model estimates California's projected annual electricity expenditures in 2020, which would be the combined revenue requirement of all of California's utilities. In addition to the cost of constructing new resources, the model also includes changes in utility costs in a number of areas such as transmission, distribution, fuel costs, and CO<sub>2</sub> allowance price, all of which result in a projection of California's total electricity expenditures in 2020 under each scenario.

The resulting average electricity cost per kWh in 2020 is the total statewide electricity expenditures divided by total retail sales. While this metric is informative, it does not show the bill impact for different customer classes. California's retail rate designs vary for each electric utility in the state, so the cost impact of meeting a 33% RPS could vary for any individual household or business.

### ***Inputs/Assumptions***

Major supply data sources of the RPS calculator are as follows: 1) CPUC Energy Division project database (ED Database- 2009 version); 2) Transmission data (Renewable Energy Transmission Initiative-RETI website, 2012); 3) The GHG calculation (GHG Calculator model, 2012); and 4) Estimates of distributed renewable energy potentials using the E3 and Black and Veatch analysis (E3, 2009).

All costs are expressed in 2008 dollars, and the model does not attempt to predict breakthroughs in technological development or changes in capital or operational costs.

The RPS assumes that all resources are developed by independent power producers (IPPs) using a 20-year financing life period. Based on the financing life time, the RPS calculates the resulting 20-year levelized \$/MWh power purchase agreement (PPA) price at a level that allows the IPP to achieve its target after-tax equity return.

Table 1 reports the main assumptions/inputs used in the RPS Calculator. Most of the demand data are from California Energy Commission's 2009 load forecast (Kavalec and Gorin, 2009). The demand inputs used in the RPS Calculator are constant forecasts from 2012 to 2020, meaning they do not respond to changes in prices (costs).

**Table 1 Main Assumptions/Inputs of the RPS Calculator**

<b>Category</b>	<b>Assumption/Input</b>
<i>Fuel price forecast</i>	<i>2009 Market Price Referent (MPR) methodology</i>
<i>CO2 allowance price forecast</i>	<i>2009 Market Price Referent (MPR) methodology</i>
<i>Load forecast and retail sales</i>	<i>Energy Commission's 2009 IEPR reference case</i>
<i>Energy efficiency achievement</i>	<i>Energy Commission's 2009 IEPR load forecast</i>
<i>Demand response achievement</i>	<i>Energy Commission's 2009 IEPR load forecast</i>
<i>Combined Heat and Power (CHP) achievement</i>	<i>Energy Commission 2009 IEPR base-case load forecast assumption for CHP penetration</i>

## MODIFYING THE RPS CALCULATOR

### *a) Randomizing Parameters- Existing Parameters*

Table 2 reports the major generic parameters that have been already added to the modified model. The total number of 551 parameters of the RPS Calculator model has been added and these parameters can become randomized or changed by adding projects in the “PIER Projects to Model” sheet. All these parameters are listed in the “PIER Parameter Draws” sheet using the same color settings shown in Table 2. The parameters are divided in seven main categories: Performance inputs (light blue), conventional generation parameters (light red), Demand parameters (light purple), Fuel cost and losses (light brown), Emissions (green), Technology costs (light orange), and Renewable generation parameters (dark green).

The relevant information for each of the included parameters is reported in the “PIER Parameter Draws” sheet. The reference sheet/cells of the parameters are reported in column C. In addition, the original values of these parameters, based on the original RPS Calculator values, are inserted in column F.

The performance inputs include: 1) Plant capacity (in MW), 2) Degradation (in percentage), 3) Operating lifetime (in years), 4) Capacity factor-AC (in percentage), 5) Capacity factor-DC (in percentage), 6) Inverter replacement costs (in \$/kW), 7) Inverter replacement time (in years), 8) Insurance expense (in \$/kW), 9) Insurance escalator (in percentage per year), 10) Integration cost (in \$/MWh), and 11) DC/AC conversion rate (in percentage).

The above mentioned items are inputted for two main conventional generation types (simple cycle combustion turbine-CT and combined-cycle gas turbine-CCGT) and various renewable technologies (Madani et al., 2011) as follows: Biogas–Landfill, Biogas-Landfill-International, Biogas–Other, Biomass, Biomass–International, Geothermal, Geothermal-International, Hydro – Small, Hydro - Small-International, Hydro – Large, Hydro – Large-International, Solar Thermal without storage, Solar Thermal with storage, Wind, Wind-International, and Solar PV technologies. Solar PV technologies are divided into the Large-Thin film, Large-Crystalline Tracking, Large-Rooftop, Small-Small Ground, Small-Mid Ground, and Small-Large Ground technology categories. Each of these Solar PV types are categorized considering four regional divisions: South Coast, North Coast, Central Valley, and Desert.

**Table 2 Existing parameters ready to be randomly affected**

		<i>Parameters</i>											
<i>Category title</i>	<i>Performance Inputs</i>	Plant Capacity (MW)	Degradation (%)	Operating Lifetime (years)	Capacity Factor - AC (%)	Capacity Factor - DC (%)	Inverter Replacement Costs (\$/kW)	Inverter Replacement Time (years)	Insurance Expense (\$/kW)	Insurance Escalator (%/yr.)	Integration cost (\$/MWh)	DC/AC Conversion rate (%)	
	<i>Conventional Generation Parameters</i>	New units CT Capacity (MW)	New units CCGT Capacity (MW)	New units On-line Date (year)	Specified units capacity (MW)	Specified units Retired capacity (MW)	Specified units capacity factor (%)	Specified units Retirement Date (year)	CHP On-Peak Availability (%)	CHP Capacity Factor (%)	Share of CHP Behind the Meter	Heat rate (Btu/kWh)	
	<i>Demand Parameters</i>	Long Run Elasticity	A_Coef Long Run (GWh)	Short Run Elasticity	A_Coef Short Run (GWh)	Total demand shift in each year (GWh)	Peak demand shift in each year (MWh)	IOU Fraction of Peak Load 2020					
	<i>Fuel Cost &amp; losses</i>	Fuel Cost (\$/MMBtu)	Fuel Cost escalation (%)	California Adder for Generation (\$)	Distribution System Losses (%)	EE System Losses (%)	CHP System Losses (%)	CSI/DG System Losses (%)					
	<i>Technology Costs</i>	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Fixed O&M escalation (%)	Variable O&M (\$/MWh)	Variable O&M escalation (%)							
	<i>Emissions</i>	2020 CO <sub>2</sub> Price Forecast (\$/ton)	CO2 Emission Rate by Fuel (lb/MMBtu)	CO2 Allowance Price (\$/ton)	NOx Emission Rate (ton/MWh)								
	<i>Renewable Generation Parameters</i>	For Each Renew. Small project availability (year)	For Each Renew. Large project availability (year)	Solar On-Peak Availability (share)	Heat rate (Btu/kWh)								

Items 1 to 3 (Plant capacity, Degradation, and Operating lifetime) of the Performance inputs category are reported for all types of technologies. Capacity factor-AC is reported for all technologies except for Solar PV ones, for which Capacity factor –DC is reported instead. The Inverter information (items 6 and 7) and the Insurance information (items 8 and 9) are also specific to the Solar PV technologies. For intermittent sources, a rough estimate of \$7.5/MWh Integration cost has been considered, as one of the included parameters. Item 11 (DC/AC conversion rate) can also be randomized.

The second main category is the Conventional generation parameters which include: New capacity for CT and CCGT units (in MW), Online date for the new power plant units, Retired capacity and retirement date for aged capacity, Combined heat and power (CHP) availability for peak and capacity factor, and Heat rate (Btu/kWh) which determines the efficiency of CT and CCGT units.

The electricity demand parameters are the next main category. The long-run and short-run demand functions' parameters (parameter A and elasticity of the functions) can be used/alterd as random input variables. Also, shifts in total demand and peak demand for different years can be inserted or randomized here. The last parameter under this category is the IOU fraction of peak load in 2020.

The Fuel cost and system losses category includes the fuel/feedstock costs (\$/MMBtu) and fuel escalation (percent) for Bio resources, Coal, Natural gas (Henry Hub), Adder for California

delivery, Uranium, Waste, and Wood variable. Also, this category includes the percentage losses in distribution, energy efficiency (EE), CHP systems, and CSI/DG (California Solar Initiative/Distributed Generation) systems.

The emissions' parameters are the 2020 CO<sub>2</sub> price forecasts (\$/ton), the CO<sub>2</sub> emission rates for different fuel types (lb/MMBtu), the CO<sub>2</sub> emission allowance auction price (\$/ton), and the NO<sub>x</sub> rates for different generation types (ton/MWh).

The last category of the included parameters is the renewable generation parameters. These parameters determine the availability dates of large and small projects for each renewable technology. These parameters are specifically effective for the generic projects, not commercial projects. In addition, the availability of solar on peak hours and the heat rate (Btu/kWh) for all the renewable types are added to the model.

Two other parameters can be modified, which are not necessarily the RPS Calculator parameters: 1) Number of draws (number of sets of draws to be made) and 2) RPS target (share of renewable generation in 2020). The values for these two parameters should be determined in the E3 and E6 cells of the "PIER Parameter Draws" sheet, respectively.

Note that many more parameters exist in the RPS Calculator that could be added as random variables. We tried to add all relevant parameters. However, we might miss some parameters. Each parameter can be added to the model following the steps described in the Setting up the model-adding parameters section.

## ***b) Price-Responsive Demand***

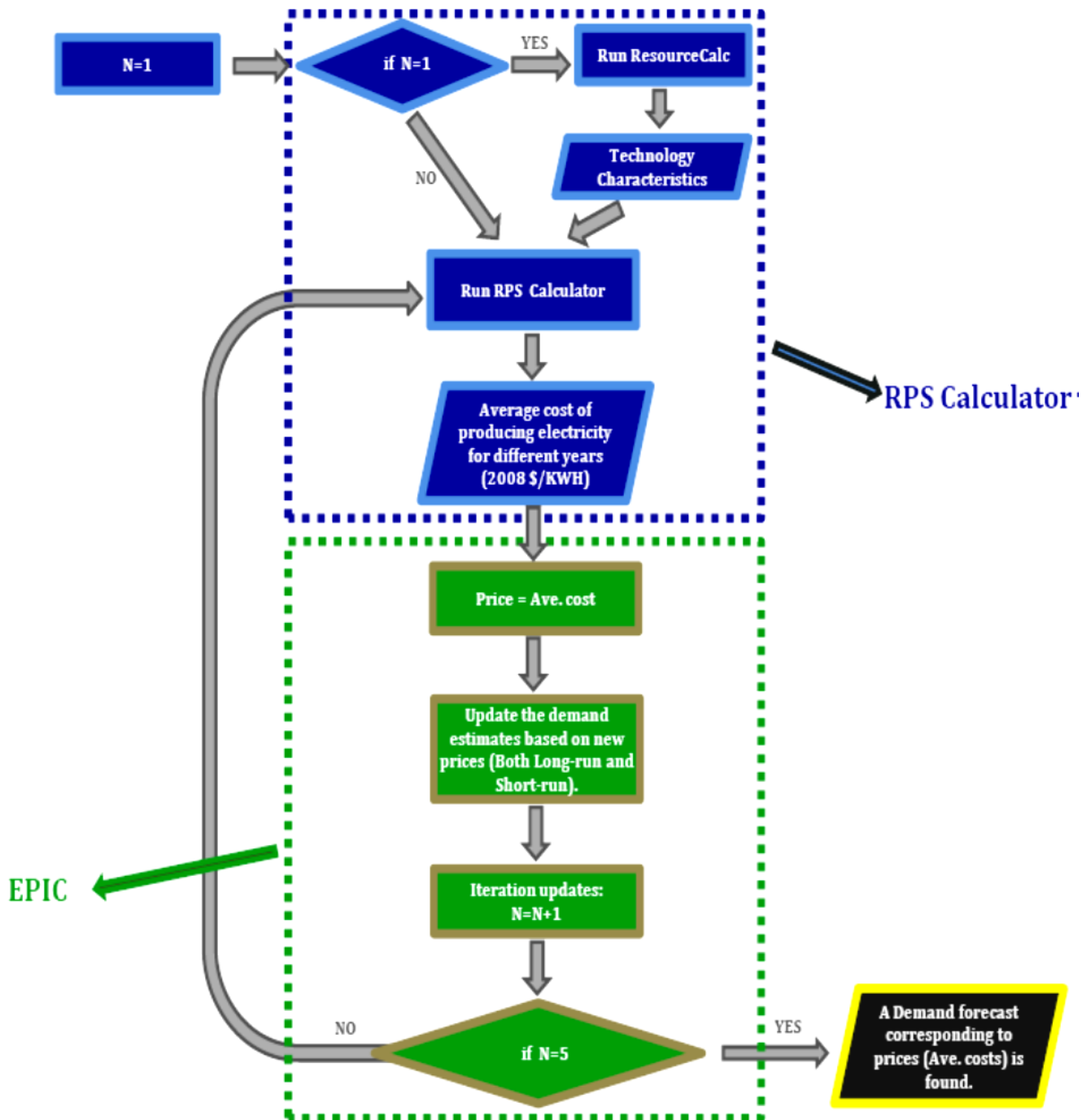
### ***b-1) Methodology***

Figure 1 shows the applied procedure to update demand forecasts, based on the implemented demand functions. Three main assumptions are made: 1) Prices equal average costs (Kavalec et al., 2012); 2) The total short-run demand in 2012 and the total long-run demand in 2020 are calculated based on the respective short-run and long-run demand functions. The total demand values between 2012 and 2020 are calculated by interpolating between the short-run 2012 demand and long-run 2020 demand values; and 3) All elements of the total demand are being updated using the updated total energy and the assumed shares in each year (see Table 3).

The procedure starts with running the RPS calculator with the original demand forecasts used in the model. The run results in average costs of producing electricity (2008\$/KWH) for 2012 through 2020. Assuming prices equal average costs, the 2012 and 2020 electricity prices are calculated. The prices, then, are used to estimate the 2012 and 2020 total demand, and the total demand between 2012 and 2020 is calculated using interpolation. The demand forecasts are replaced by the new calculated demand values. Now, the RPS calculator is run but with the

updated demand values, which results in new average costs, new prices, and new demand values consequently. This procedure can be repeated until the demand values and prices (average costs) converge to corresponding values ( $\text{Demand}(\text{iteration } N) = \text{Demand}(\text{iteration } N-1)$ ). However, because of limited computation time, we only use 5 iterations, which in most cases results in no more than 1% of deviation in the demand values. The outputs of the procedure are the demand forecasts between 2012 and 2020.





**Figure 1 Procedure of Adjusting Demand Forecasts**

The total energy demands are not the only elements of demand inputs in the RPS Calculator. Table 3 shows different categories of demand used as inputs in the model, their source sheet, and a brief description about the elements considered under each category.

The current format of the program is that all these elements are updated using the new total energy demand and the assumed shares in each year. For example, the total embedded Energy Efficiency (EE) in a year can be calculated by multiplying the total energy demand by the share of EE for the year. The assumed shares are determined using the base RPS Calculator shares (e.g., share of EE= total embedded EE/ total energy demand using the original RPS values).

**Table 3 Elements of the Demand Forecasts**

<i>Category</i>		<i>Source Sheet</i>	<i>Description</i>
1	Base Demand	"e - LoadsAndResources"	1) Peak Embedded CSI/DG; 2) Peak Embedded EE; 3) Embedded EV Peak Impact; 4 )Peak Estimate of Statewide Coincident Peak (MW); 5) Total Embedded CSI/DG; 6) Total Embedded EE; 7) Total Embedded EV consumption; <b>8)Total End Use Loads</b> ; and 9)Total Losses.
2	Provider demand	"e - LoadsAndResources"	Forecast of End-Use Loads by Provider
3	Provider demand-reduction	"e - LoadsAndResources"	Assumed Retail Sales Reductions (GWh)
4	Provider demand - total	"f - RPSNetShortCalc"	Total Demand and Energy for few Number of Providers
5	Load decrements	"d - GeneralInputs"	Demand Response/reduction in IUO's for Peak and Net Energy

\* For all, peak demand values are in terms of MWH and total demand values are in terms of GWH.

To update demand forecasts, we used simple Cobb-Douglas functions considering the following functional form: Demand = A × (Price)<sup>e</sup>, where A is a constant, price of electricity is in \$/kWh, e is the elasticity, and Demand is in terms of annual GWh. Table 4 reports the demand functions' components used to update demand forecasts in the model. The short-run elasticity of -0.1 and long-run elasticity of -0.85 have been assumed. These assumptions are close to the averages found by other studies (Espey and Espey, 2004; Bernstein and Griffin, 2006; Kavalec, 2012), which can be observed on Table A1 (Appendix). However, categorizing the total electricity demand into sectors can provide better estimates. The addition of the sectors can be our future development.

**Table 4 Demand Functions Used for Updating Demand Forecasts**

	<i>Category</i>	<i>Long-run</i>	<i>Short-run</i>	<i>A</i>	<i>e</i> <i>(elasticity)</i>
1	Total electricity	√		68234	-0.85
2	Total electricity		√	244000	-0.1

## ***b-2) Impacts of Using Responsive Demand***

This section examines the effects of applying the changes on the RPS Calculator. To compare the effects across various scenarios, we chose a base case (Table 6) with a set of assumptions presented in Table 5, and all alternative cases are selected by applying a change in one of the base case's assumptions.

**Table 5 Major Assumptions of the Base Case**

No.	Category	The Assumption	Note
1	<b>Scenario / Ranking Score Weighting</b>	Cost	Policy objective: Cost, Time, or Environment
2	<b>REC Eligibility</b>	No Out-of-state REC Restriction	Possibility of Renewable Electricity Credit from outside CA
3	<b>RPS % in 2020</b>	33%	
4	<b>Existing Transmission Build</b>	Existing Transmission w/Minor Upgrades	With or without minor upgrades
5	<b>Active Discounted Core</b>	Discounted Core 6	Discounted core-Most viable projects with signed contracts
6	<b>Large Scale Solar PV Resource</b>	Thin Film	Thin Film or Crystalline
7	<b>Price Cap on RECs</b>	No Cap	The cap on price of REC
8	<b>Gas Price Scenario</b>	Base Case	\$7.95/MMBTU (2009 MPR)
9	<b>CO2 Price Scenario</b>	Base Case	\$43.52/ton (2009 MPR)
10	<b>RETI Solar Resources</b>	Large Scale Solar PV	The emerging Solar technology
11	<b>Configuration for lines from WY, MT</b>	Alternating Current	Alternating or Direct Current
12	<b>Load Scenario</b>	Base Case	Base from 2009 CEC IEPR or 10% higher or lower

Table 6 show the assumptions made for all the other cases (cases 1 to 9) as well as for the base case. Then, we examine the effects of updating demand on each case. For each of these cases, two scenarios can be used: one without the demand updates-original model (original RPS calculator with fixed demand forecasts), and the other with updating demand (the modified model- resulting from running the RPS iteratively, as shown in Figure 1). We examine the effects of using each scenario on the results of various cases.

**Table 6 Characterization of Cases**

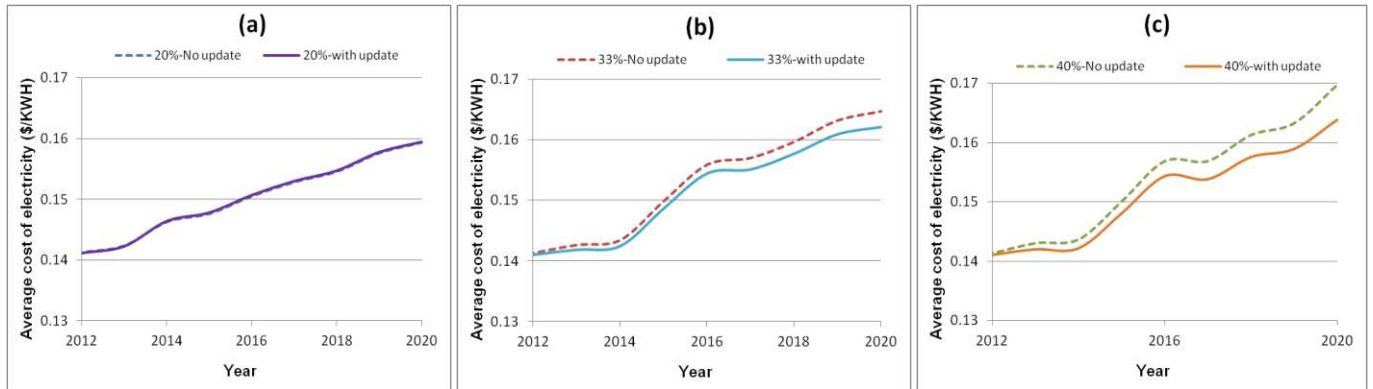
Case	1) Ranking score weighting	2) REC eligibility	3) RPS% in 2020	4) Transmission build	5) Discounted core	6) Large solar resource	7) Price cap on REC	8) Gas Price	9) CO <sub>2</sub> price	10) RETI Solar resources	11) Lines from WY and MT	12) Load Scenario
Base case	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	Base	Large solar PV	Altern. current	Base case
1	Commercial	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	Base	Large solar PV	Altern. current	Base case
2	Environment	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	Base	Large solar PV	Altern. current	Base case
3	Permitting	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	Base	Large solar PV	Altern. current	Base case
4	Cost	No restrict	33%	Existing no upgrades	#6	Thin film	No cap	Base	Base	Large solar PV	Altern. current	Base case
5	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	\$50 max	Base	Base	Large solar PV	Altern. current	Base case
6	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	High	Base	Large solar PV	Altern. current	Base case
7	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Low	Base	Large solar PV	Altern. current	Base case
8	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	High	Large solar PV	Altern. current	Base case
9	Cost	No restrict	33%	Existing& minor upgrades	#6	Thin film	No cap	Base	Low	Large solar PV	Altern. current	Base case

Table 7 shows the results of running the model for the cases introduced in Table 6. The modified model (with the demand updating feature), as well as the original model (with no demand updating), are run. Table 7 reports the resulting total energy use (GWh), average cost of generating electricity (\$/kWh), and CO<sub>2</sub> allowances (tones). For all the studied cases, the addition of demand responses to prices decreases total demand (total energy), average cost, and CO<sub>2</sub> allowances. For most cases, the addition of flexible demand feature does not dramatically decrease average costs while significantly decreases total energy and CO<sub>2</sub> allowances. The effects of the updating on Case 6 (high natural gas price) are the highest. Also, an important conclusion can be made considering case 6 (highlighted): when the change in total energy is significant, we may need to add more iterations (more than 5) to the procedure shown in Figure 1.

**Table 7 Results of model for all cases without and with the demand updates (for 2020)**

<i>Cases</i>	Total Energy (GWH)		Average Cost (\$/KWH)		CO2 Allowances (tones)	
	<i>No Demand Updates</i>	<i>With Demand Updates</i>	<i>No Demand Updates</i>	<i>With Demand Updates</i>	<i>No Demand Updates</i>	<i>With Demand Updates</i>
<i>Base case</i>	326,882	319,900	0.1647	0.1622	90.07	86.9
1	326,882	317,294	0.1659	0.1629	90.17	86.73
2	326,882	315,894	0.167	0.1636	89.94	85.98
3	326,882	317,911	0.1654	0.1626	90.17	86.94
4	326,882	318,755	0.1652	0.1625	90.09	86.73
5	326,882	319,262	0.1643	0.1619	89.59	86.85
6	326,882	297,817	0.1825	0.1695	90.16	79.73
7	326,882	324,702	0.16	0.1594	90.09	89.31
8	326,882	317,378	0.1658	0.1626	90.03	86.61
9	326,882	319,979	0.1637	0.1617	90.09	87.6
10	326,882	325,565	0.1593	0.1589	103.06	102.59
11	326,882	312,801	0.1697	0.1653	85.07	80

Figure 2 shows the average costs of generating electricity to meet various RPS targets (from 2012 to 2020). The dotted lines show the results of the original model with constant demand, and the solid lines show the results of the modified model with the updating demand feature. The average costs are always lower for the modified model than for the original RPS Calculator. The main reason is that the CEC 2009 demand forecasts (CEC, 2009) are calculated without considering the demand responses (reductions) to higher prices (average costs), resulting from meeting a higher RPS target which uses more expensive renewable resources. When demand decreases as a response to a price increase, the cost of meeting an RPS target will decrease and as a result, the average cost will be reduced. Also, the modified model changes the renewable resource mixes but the changes are not substantial (Rouhani et al., 2013b).

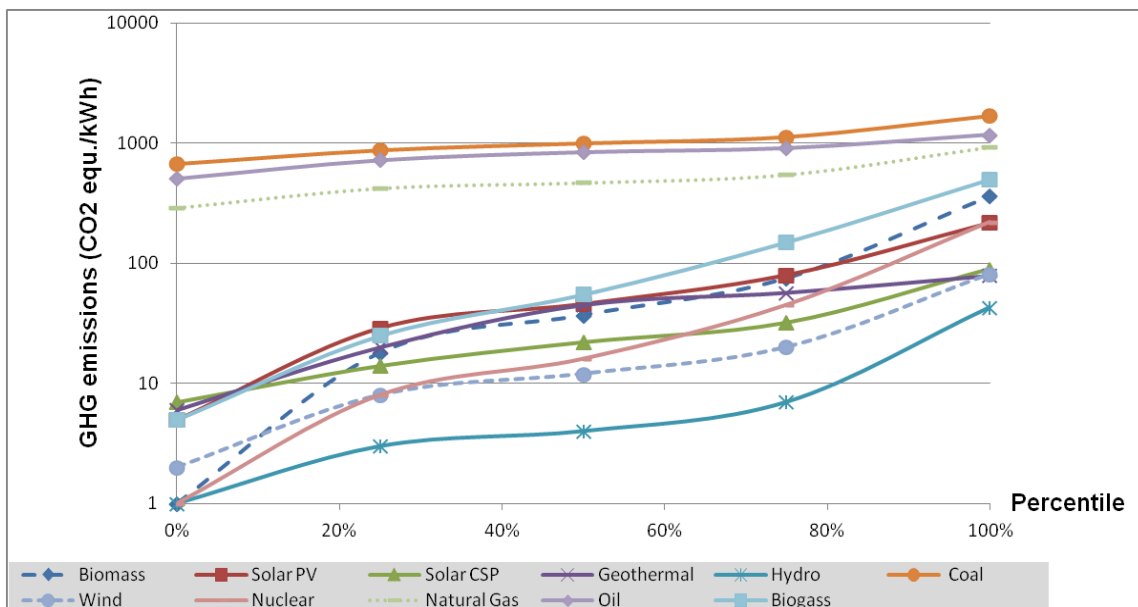


**Figure 2 Average cost of electricity to meet RPS for (a) 20% target; (b) 33% target; (c) 40% target**

### *c) GHG Calculations*

GHG estimations are critical for the environmental sustainability concept (Rouhani, 2009). Our GHG emissions' calculations are based on two sets of emission rates: 1) the non-life-cycle analysis (non-LCA) values borrowed from the RPS Calculator, and 2) the LCA values from the IPCC study (IPCC, 2011, Rouhani, 2013b), which are obtained reviewing a wide range of the LCA studies. The LCA values are reported in the “PIER LCA Calculations” sheet-Row 6.

Figure 3 shows the range of the LCA emission rates (g CO<sub>2</sub> eq./kWh) for each electricity generation technology, using the rates obtained from the various studies (IPCC, 2011). The LCA values are reported in the “PIER LCA GHG” sheet, cells from D4 to N8.



**Figure 3 GHG emission rates for various electricity generation technologies**

The default LCA values in the model are the median (50% percentile) values of the IPCC study (IPCC, 2011). These values are listed in the 6<sup>th</sup> row of the “PIER LCA Calculations” sheet. The default non-LCA value for natural gas generation is based on the RPS adopted value (117 lb CO<sub>2</sub>/MMBTU). The corresponding value (181 gr CO<sub>2</sub>/kWh) is reported in the N6 cell of the “PIER Non- LCA Calculations” sheet. If you wish to use other values for the non-LCA and LCA values, you can change the values in the N6 cell and the 6<sup>th</sup> row of the corresponding sheets respectively, and run the model with these new values.

The changes in GHG emissions from base case (with no PIER projects) to the current case are calculated in the “PIER LCA Calculations” sheet and the “PIER Non- LCA Calculations” sheet. The calculations are based on the estimated changes in the current generation mix relative to the base case mix, considering 1) the changes in each renewable generation type (GWh-row 25 to row 32) multiplied by the corresponding emission rate for the renewable type (gr CO<sub>2</sub> eq./GWh-row 6), and 2) the change in conventional generation (GWh-row 38) multiplied by the natural gas emission rate (g CO<sub>2</sub> eq./GWh-cell “N6”). In fact, we assume that all changes in conventional generation result from the changes in natural gas generation.

For each set of randomly drawn parameters, we report the renewable generation mix for the base case (cells “U12 to “AE20”) and for the current mix (cells “E12” to “O20”) from 2010 to 2020. Also, we report the change in the total electricity demand of the current case relative to the base case (row 36), resulting from the change in the electricity prices (average costs). Then, the change in total demand can be used to calculate the change in conventional generation for different years, as follows:

change in conventional = change in total demand- change in the sum of all renewable.

Knowing the changes in both renewable and conventional generation (in GWh), we determine the changes in GHG emissions for different years by multiplying the change in each generation type to the corresponding emission rate for the generation type. For each set of random draws, the outputs of the calculation are the changes in GHG emissions from the base case in different years-2010 to 2020 (Cells E41 to O41 in the “PIER LCA Calculations” sheet). The results are stored in the “PIER Outcome Draws” sheet (in the BL to BV columns). The calculations are repeated for different sets of random draws.

#### **d) Labor Calculations**

California's Clean Energy Future (2012) provided estimates of job creation rates (the number of job-years per GWh) for different types of generation, as shown in Table 8. Using these rates, we calculate the changes in labor from the current case relative to the base case, as a result of any change in the generation mix.

**Table 8 Job-years per GWh for various generation types**

	Energy Technology								
	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Energy Efficiency
<b>Job-years/GWh</b>	<b>1.31</b>	<b>1.31</b>	<b>0.72</b>	<b>0.77</b>	<b>0.69</b>	<b>1.14</b>	<b>0.41</b>	<b>0.1</b>	<b>0.32</b>

The change in labor is calculated in the “PIER Labor Calculations” sheet. The first step is differentiating between instate and out of state generation since out of state generation has no effect on the California’s labor. We report the 2020 instate generation mix both for the current draw in cells G7 to I15 and for the base case (no EPIC projects) in cells L7 to N15. Also, we save the change in the total annual demand from the base case to the current case in cell I23. Now, we can calculate the change in labor based on two factors: 1) the change in each instate generation type multiplied by the corresponding rate in the Table, 2) the change in energy efficiency reductions multiplied by its rate. We assume that the change in energy efficiency is a function of a portion of change in demand. So if the total demand decreases, a percentage of this decrease will be from energy efficiency reductions. This percentage is assumed to be the original (RPS Calculator’s value) share of energy efficiency from total energy ( $24.5\% = 78.8/321$ ).

The 2020 change in labor values, relative to the base case, are reported in the “L22” cell of the “PIER Labor Calculations” sheet for each set of draws. Also, this value is shown in Column BX of the “PIER Outcome Draws” sheet for all sets of draws.

## SETTING UP THE MODEL

### *Adding Projects*

To include the effects of each EPIC project, you should add the project information details to the "PIER Projects to Model" sheet. The project information includes the following items (however, Columns A to E should be also filled for the general, but not effective, information related to the projects):

1) Type of Benefit (Column G) is the parameter (input) of the original RPS calculator which will be affected by the EPIC project. You can choose the type of benefit from the dropdown menu. If you do not see the parameter you want, you will need to add the parameter (see the Adding Parameters section).

2) Amount of Benefit Achieved at Full Market Penetration<sup>1</sup> (Column H) is the absolute amount of change in the parameter if the EPIC research was fully used. In most cases, this will be the change in the parameter observed in the demonstration project. If you want a relative change in the parameter (i.e. decrease by 10%), use an Excel function which references the original value on the sheet “PIER Parameter Draws”-column F or manually calculate and enter the amount of change. To randomize the potential benefit (in addition to the market penetration), you can use an Excel function like rand(), for instance “=rand\*0.1+4” would draw a value between 4 and 4.1.

3) Projected Market Penetration (Column I) is the central value of the penetration of the project's benefits, around which the draws will be distributed. This value represents the distribution mean which will be used for drawing. This value is required for determining the shape of the distribution to be used for drawing.

4) Distribution for Market Penetration Draw (Column L) determines the type of distribution for randomly drawing. Choose the distribution from the dropdown menu. Other distributions can be added in principle, but some VB coding is involved.

5) Upper and Lower bounds (Column J and K) of the distribution should also be set.

For empirical distributions, we should not use the above mentioned items for drawing. The values are drawn directly from the empirical distribution data. For each simulation draw, a row of the empirical distributions data is used orderly (i.e., the first data row for the first draw, the second data row for the second draw, etc.)

In order to add new empirical distributions, add the names you want to use for the distributions to the list in Column U of the “PIER Projects to Model” sheet, after the existing distributions’ names. The names will be shown in the drop-down menu (column L) of the sheet, for choosing the distribution type (item 4, above list). After adding the distribution name, find the cell named “from this point” (Z2) in the sheet. Insert the same name for the distribution (which should be a unique name) in row 4, after the “From this point on” cell-Z2. Then, add the data (random draws) for the distribution right below the name (in the same column).

### ***Adding Parameters***

The existing parameters (affected by EPIC projects) are listed in the “PIER Parameter Draws” sheet, which are also shown in the drop-down menu (column G) of the “PIER Projects to Model” sheet. The parameters’ names can be found in Column E of the “PIER Parameter Draws” sheet. Additional parameters can be added using the following procedure:

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<sup>1</sup> For the definition of market penetration please see Bunch et al. (2011).



First, find the parameter or parameters the EPIC projects affect in the RPS calculator sheets. The parameters are located in various cells of the Excel sheets. In the current RPS Calculator version, most technological costs, performance inputs, and capacity factors are in the “a-ProForma” sheet, some system loss characteristics are inserted inside the “d – GeneralInputs” sheet, and most electricity demand elements are inputted in the “e – LoadsAndResources” sheet.

You need to find where the parameter (in which cell) is recorded as a fixed number, as opposed to an Excel formula. The cells referring to a formula cannot be used because these cells/variables depend on other inputs/parameters of the model and are used for intermediate or final calculations.

After finding the parameters, copy the original number into the Column F of the “PIER Parameter Draws” sheet, and then replace the original cell with a formula pointing to the Column H of “PIER Parameter Draws” (in the same row of the original number). Add a description (parameter name) in Column E. This will show up in the dropdown menu for Benefit Types in the “PIER Projects to Model” sheet.

For each parameter, you can also add a category name, original sheet/cell, and comments in the Columns B, C, and D of the “PIER Parameter Draws” sheet, respectively. This is optional, but it will make it easier to find cells or to update the model. Also, the cell colors used should follow the color setting shown in Table 2.

## **REINSTALLING THE MODEL**

This section explains the required steps to install the model on newer versions of the RPS Calculator. CPUC and E3 will update the RPS Calculator regularly. Each new version revises the errors/data in the earlier versions or adds more data/calculations to the analysis. To modify our model using the newer versions, we should set up our model on the new RPS Calculator file.

The first step to install our model is the addition of the sheets used by the EPIC model. These sheets include: “PIER Instructions” which is just a summary of how to use the model, “PIER Projects to Model” which encloses the information related to the EPIC projects and their effects on the model’s parameter, “PIER Parameter Draws” which lists all the model’s parameters which can be affected by EPIC projects, “PIER Outcome Draws” which is used for reporting the results, “Densities” which contains the density diagrams (figures) based on the results, the “PIER LCA Calculations” sheet which calculates the LCA change in GHG emissions, the “PIER Non-LCA Calculations” sheet which calculates the non-LCA change in GHG emissions, and the “PIER Labor Calculations” sheet which calculates the change in labor. So, first we should add these sheets with the exact same name used in the previous EPIC modified version (shown above).

For the next step, you should copy paste the information from the previous sheets to these newly added sheets. The copying should be done very carefully.

One of the main challenges installing the model on the new RPS Calculator is that the name of the sheets or even the name of the existing parameters might be changed, which can cause problems both for referencing parameters and for running the VB program.

The third step is that referencing should be applied to the parameters of the new RPS Calculator model.

The fourth step is the attachment of the VB program to the new model.

The result will be a new EPIC model which can be run using the new RPS Calculator features.

## **FUTURE ADDITION TO THE MODEL**

We prepared the following list for the future possible additions to the model:

- The market penetration for each parameter (project) is assumed to affect all projects instead of affecting a portion of projects that use the new technology. And as an alternative approach, we used a (market penetration-based) portion of the change in the parameter resulting from a project, i.e. if a project decreases capital cost of wind generation for 100\$/kW, and its market penetration is estimated at 20%, we will use - 20\$/kW for the central value of the parameter. To fix this approximation, we need to run the program using the actual change (in the example \$100/kW), record the wind projects added, and finally choose a percent (20%) of these projects, based on their generation size or even a percent of their generation.
- Another important addition is the inclusion of separate demand shifts for different demand elements. For example, we should assign a separate value for energy efficiency shifts which can be used for labor calculations. However, in general, annual shifts in total energy demand and annual shifts in peak demand are sufficient for most purposes.
- One alternative option to using the new versions of the RPS Calculator is replacing the projects database in the old version with the new project database. But using a new version of the RPS Calculator should be preferred.
- Conventional generation is not comprehensively considered in the RPS Calculator, and consequently our model. The future of conventional generation is hard to predict (Mirchi et al., 2012). A future work can address this limitation.
- Implementing one price elasticity of demand for the whole electricity sector is questionable. Addition of different sectors of electricity demand can be a valuable future development. Also, the demand functions can be improved by using non-constant-elasticity functions like Trans-Log functions and by adding other important parameters than price like lagged price, income and some other macro parameters.

- The original version of the program calculates the results of applying a set of EPIC projects together. The alternative version of the program should calculate the results of applying EPIC projects individually. Basically, each project's individual effects on the RPS Calculator's parameters and consecutively our model's results should be reported. The results can be calculated using five (two) different draws of the probable effects of EPIC projects effects: low, medium low, medium, medium high, and high. The final output is the changes in the average retail rates-electricity prices in different years, total revenue requirement, total CO<sub>2</sub> allowances, and 2020 renewable generation reported under five different conditions for all projects (500 (200) sets of outputs for 100 projects).
- A procedure to choose an optimal combination of the CEC projects with a limited budget. Considering that a combination of projects can have completely different effects than the sum of the individual projects' effects (Rouhani and Niemeier, 2011; Rouhani et al., 2013*b*). Therefore, we need to solve a combinatorial optimization problem (Poorzahedy and Rouhani, 2007; Rouhani, 2013*a*; Madani et al., 2014).

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The author certifies that he has the right to deposit the contribution with MPRA.

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## APPENDIX- *Electricity Demand's Elasticities from Various Research Studies*

The Table A1 shows the short-run and long-run elasticities estimated by various studies. An important note is that the elasticities are different for different sectors but some studies have estimated the average elasticities across all sectors.

**Table A1 Long-run and Short-run Elasticities from Various Studies**

<i>Research Study</i>	Residential		Commercial		Industrial		Total	
	<i>Long-run elasticities</i>	<i>Short-run elasticities</i>	<i>Long-run elasticities</i>	<i>Short-run elasticities</i>	<i>Long-run elasticities</i>	<i>Short-run elasticities</i>	<i>Long-run elasticities</i>	<i>Short-run elasticities</i>
1 <i>Dahle(1993)</i>	-	-	-	-	-	-	-	0.14-0.44*
2 <i>Espey and Espey (2004)</i>	-	-	-	-	-	-	0.85 (0.04-2.25)	0.35 (0.004-2.01)
3 <i>Bernstein and Griffin (2006)</i>	California 0.49	California 0.32	California 0.31	California 0.20	-	-	-	-
	0.32	0.24	0.97	0.21	-	-	-	-
4 <i>CEC 2012</i>		California 0.10		California 0.15		California 0.10		

\* Elasticities are reported for the U.S. unless it has been stated.

**Table A2 of California Energy Demand 2012-2022 Final Forecast**  
**(Kavalec et al., 2012, Table1 page13)**

Consumption (GWh)				
	<i>CED 2009</i>	<i>CED 2011 Final High Energy Demand</i>	<i>CED 2011 Final Mid Energy Demand</i>	<i>CED 2011 Final Low Energy Demand</i>
1990	228,473	227,586	227,586	227,586
2000	264,230	261,381	261,381	261,381
2010	280,843	273,103	273,103	273,103
2015	299,471	297,509	291,985	283,011
2020	318,280	322,760	310,210	301,535
2022	--	333,838	318,071	308,677
Average Annual Growth Rates				
1990-2000	1.46%	1.39%	1.39%	1.39%
2000-2010	0.61%	0.44%	0.44%	0.44%
2010-2015	1.29%	1.73%	1.34%	0.72%
2010-2020	1.20%	1.68%	1.28%	1.00%
2010-2022	--	1.69%	1.28%	1.03%
Noncoincident Peak (MW)				
	<i>CED 2009</i>	<i>CED 2011 Final High Energy Demand</i>	<i>CED 2011 Final Mid Energy Demand</i>	<i>CED 2011 Final Low Energy Demand</i>
1990	47,521	47,546	47,546	47,546
2000	53,703	53,700	53,700	53,700
2011	--	58,737	58,737	58,737
2011*	63,282	60,310	60,310	60,310
2015	66,868	65,950	65,038	61,791
2020	71,152	71,701	69,418	65,884
2022	--	74,049	70,946	66,916
Average Annual Growth Rates				
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2011	1.50%	0.82%	0.82%	0.82%
2011-2015	1.39%	2.33%	1.93%	0.72%
2011-2020	1.31%	1.97%	1.58%	1.05%
2011-2022	--	1.91%	1.50%	1.00%
Historical values are shaded.				
*Weather-normalized: <i>CED 2011 Final</i> uses a weather-normalized peak value derived from the actual 2011 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2012